Assessment of Impacts and Mitigation Approaches

on Near Term Coal Reduction and Power System Dispatch of Datan Conventional Gas Terminal

Dung-Bai (Tony) Yen

MSc. Renewable Energy Engineering and Management, University of Freiburg

See the commented version here

Introduction

The conventional gas terminal at Datan power plant is planned to start operation by late 2022, supplying 2 CCGT with a total of 2 GW of maximum capacity.

However, the gas terminal requires the construction of a new port, under which a coralline algae ecosystem might be irreversibly damaged. In addition, conventional gas terminals will not be suitable for importing green hydrogen in the long term future, thereby they are subject to becoming stranded assets during the energy transition.

A referendum has been initiated by environmental groups in Taiwan to halt the project; this assessment report investigates what could happen to near term coal reduction and power system dispatch if such referendum is passed.

Coal Reduction Impact Estimation

Without the terminal, there will be an annual shortage of 1.41 million tonnes of conventional gas supply in Taiwan by 2025.

Assuming this supply gap will be met by additional coal consumption in the electricity sector, this will result in 3.28 million tonnes of additional coal consumption, or 4.36 million tonnes of additional carbon emissions annually.

Coal Reduction Impact Estimation

Calculation:

Electricity gap due to gas supply shortage = (1.41 * 10^9) / 0.75 (conversion factor to m^3) * (9 * 10^6) (heat value cal/m^3) * 4.18 * 0.55 (average efficiency CCGT)

Additional Coal Consumption = Electricity gap / .4 (average efficiency coal) / (7100 * 10^3 * 4.18) (energy density of coal)

Additional Carbon Emission = Additional Coal Consumption * 2.4081 - (1.41 * 10^9) / 0.75 * 1.879

Power System Dispatch Impact Estimation

To investigate the impact of delay / cancellation of the terminal construction will have on the power system dispatch, we will solve a minimum emission dispatch problem with a power system dispatch model of Taiwan by 2025.

Dispatch Model: Assumptions

1. Electricity demand in Taiwan will grow by 10% by 2025, compared with 2020.

2. Gas supply constraint: in the congestion free case, we assume daily gas consumption of the power system can not exceed 80% of the import capacity (estimated from power system data in 2020) of Taiwan; in the congestion case we assume no additional gas transmission capacity is available for Datan power plant, so it can only operation 7 CCGT at full load at most at any given time.
   (The actual gas pipe transmission constraint must be in between the 2 extreme cases; information on the gas pipe transmission capacity and gas demand profile would be needed to make assumptions that can better reflect reality.)

Dispatch Model: Assumptions

3. Demand and generation of electricity is balanced at any given time.
4. 10% of the residual load of control reserve capacity must be kept at any given time.
5. Technical constraints (start-up time, ramp limits, minimum compliant load, etc.) of the power plants must be honored.
6. Fuel consumption variations due to operational efficiency change are neglected, so the problem remains a mix-integer linear problem.

Dispatch Problem: Objective Function

$$min \sum_{t,i} e_i \cdot cpp_i(t) \cdot \Delta t + e_{u,i} \cdot u_i(t)$$

Where

e_i : emission factor of running conventional power plant i

cpp_i(t): power output of conventional power plant i at time t

e_{u,i}: emission factor of starting conventional power plant i

u_i(t): a time series of binary variables indicating when start-up events of conventional power plant i occurs

Dispatch Problem: Supply and Generation Constraints

$$\sum_i cpp_i(t) \geq RL(t) \forall t$$

Balancing constraint

$$\sum_{i\in\{Gas\},j\in\{GT_i\},t} \frac{cpp_{i,j}(t)}{\eta_i} \cdot \Delta t \leq Gas_{\max}$$

Gas consumption constraint

$$\sum_{i\in\{Datan\},j\in\{GT_i\}} cpp_{i,j}(t) \leq Datan_{\max} \forall t$$

Gas transmission capacity constraint

Where

RL(t): residual load at time t

eta_i: thermal efficiency of power plant i

Gas_{max}: maximum available gas within a time interval

Datan_{max}: maximum possible power output at Datan

Dispatch Problem: Control Reserve Constraints

$$flex_{u,i}(t) \leq s_i(t) \cdot cpp_{\max,i} - cpp_i(t) \forall i,t$$ Headroom constraint

$$flex_{u,i}(t) \leq ru_{\max,i} \forall i,t$$ Upward flexibility constraint

$$\sum_i flex_{u,i}(t) \geq max\{flex_{u,min}, 0.1 \cdot RL(t)\} \forall t$$ Positive control reserve constraint

Where

flex_{u,i}(t): upward flexibility of power plant i at time t

cpp_{max, i}: maximum available power output

ru_{max}: maximum ramp up rate

s_i(t): binary variable indicating the operation state of power plant i at time t

Dispatch Problem: Control Reserve Constraints

$$flex_{d,i}(t) \leq cpp_i(t) - s_i(t) \cdot cpp_{\min,i} \forall i, t$$ Footroom constraint

$$flex_{d,i}(t) \leq rd_{\max,i} \forall i, t$$ Downward flexibility constraint

$$\sum_i flex_{d,i}(t) \geq max\{flex_{d,min}, 0.1 \cdot RL(t)\} \forall t$$ Negative control reserve constraint

Where

flex_{d,i}(t): downward flexibility of power plant i at time t

cpp_{min, i}: minimum available power output

rd_{max}: maximum ramp down rate

Dispatch Problem: Technical Constraints

$$cpp_i(t+1) - cpp_i(t) \leq ru_{max} + u_i(t) \cdot (cpp_{min,i} - ru_{max}) \forall i, t$$

Ramp up constraint

$$cpp_i(t) - cpp_i(t+1) \leq rd_{\max} + d_i(t) \cdot (cpp_{\max,i} - rd_{\max}) \forall i, t$$

Ramp down constraint

$$s_i(t) \cdot cpp_{min,i} \leq cpp_i(t) \leq s_i(t) \cdot cpp_{max,i} \forall i, t$$

Power output constraint

$$s_i(t+1) = s_i(t) + u_i(t) - d_i(t) \forall i, t$$

State Evolution Constraint

Dispatch Problem: Technical Constraints

$$d_i(t) + u_i(t+\tau) \leq 1 \forall i, t = \{0, 1, ..., T-\tau\}, \tau = \{1, 2, ..., su_{min,i}\}$$

Start-up time constraint

$$s_{i,ST}(t) \leq \sum_{j \in \{GT_i\}} s_{i,j}(t) \forall i \in \{CC\}, t$$

Start-up order constraint for combined cycle steam turbines

Where

su_{min, i}: minimum start-up time for power plant i

s_{i,ST}(t): state variable for the steam turbine in a CCGT

s_{i,GT}(t): state variable for the gas turbines in a CCGT

Dispatch Problem: Technical Constraints

$$cpp_{i,ST}(t) \leq \alpha \cdot \sum_{j \in \{GT_i\}} cpp_{i,j}(t) \forall i \in \{CC\}, t$$

Power output constraint for combined cycle steam turbines

Where
alpha: coefficient determining the maximum extractable waste heat from the gas turbine
cpp_{i,j}(t): power output of a ST/GT in a CCGT.

Dispatch Problem: Technical Constraints

$$\frac{1}{N_i} \sum_{j \in \{GT_i\}} s_{i,j}(t) \leq s_{GT_i}(t) \leq \sum_{j \in \{GT_i\}} s_{i,j}(t)$$

$$s_{GT_i}(t) - s_{GT_i}(t-1) + u_{i,ST}(t+\tau) \leq 1 \forall i \in \{CC\}, t = \{1, 2, ..., T-\tau\}, \tau = \{1, 2, ..., su_{min,i,ST}\}$$

Start-up time constraint for combined cycle steam turbines

Where

s_{GT_i}(t): binary variables indicating whether any of the GT in a CCGT is operating.

N_i : Number of GTs in CCGT i.

Dispatch Problem: Mathematical Constraints

$$u_i(t) \in \{0,1\} \; d_i(t) \in \{0,1\} \; s_i(t) \in \{0,1\} \; s_{GT_i}(t) \in \{0,1\}$$

Binary variables

$$cpp_i(t) \geq 0$$

Non-negative variables

$$\forall i, t$$

Dispatch Problem: VRE Modeling

As a conservative model, we assume the VRE power plants are totally inflexible, i.e. they cannot contribute to the control reserve requirement of the system.

This assumption is probably trivial because curtailment is still not an issue by summer 2025; with enough storage and other flexibility options the minimum residual load is still safely above the system must run. In winter 2025 this might prove to be an issue, but that is beyond the scope of this assessment report.

The effective load carrying capacity for VRE in the annual schedule problem is also a conservative estimation; we assume only during summer and only solar PV has ELCC.

Dispatch Problem: Non-Hydro DRE Modeling

We will assume that bioenergy, waste, and geothermal power plants runs at a constant power output that is derived empirically from the annual average capacity factor of 2020.

This means bioenergy power plants runs at 23.2% of full capacity, waste power plants at 64.2%, and geothermal power plants at 72.5%.

We assume that geothermal will increase to 0.040 GW by 2025; the capacity of other types of DRE remains the same compared with 2020.

Dispatch Problem: Non-Hydro DRE Modeling

Overall this translates into around 0.453 GW of constant non-hydro DRE output. Since the firm capacity factor for waste power plants is 70.3%, this translates into 0.039 GW of additional positive control reserve. Meanwhile, since Taipower assumes 50% effective load carrying capacity factor of bioenergy power plants, this translates into 0.021 GW of additional positive control reserve. In total non-hydro DRE power plants provide 0.060 GW of additional positive control reserve (upward flexibility of geothermal power plants is not considered).

Assuming non-hydro DRE power plants are fully flexible, the constant non-hydro DRE output of 0.453 GW can be added into the negative control reserve.

Dispatch Problem: DR Modeling

Currently Taipower purchased about 1.5 GW of demand response; they are however mostly voluntary programs with no penalties. We therefore do not consider these flexibility resources as reliable control reserve capacity in the dispatch problem; nonetheless we assume that these resources have an effective load carrying capacity factor of 20% when solving the annual schedule problem presented later.

We assume that by 2025 there will be 200 MW of reliable DR for positive control reserve; this is in line with Taipower's current plan of purchasing 800 MW of control reserve from unconventional resources (batteries, DR, VRE, etc.).

Dispatch Problem: CHP Modeling

About 4.968 GW of coal CHP is currently installed in Taiwan; of which Taipower assumes 1.474 GW of effective load carrying capacity.

We thus model the coal CHP power plants to be a fully flexible generation unit with a peak capacity of 1.474 GW. The thermal efficiency of coal CHP is assumed to be 65%, and the carbon emissions per kWh is calculated accordingly.

Only 0.025 GW of Oil CHP currently exists in Taiwan and they do not account for any effective load carrying capacity, so they are neglected in our model.

Annual Plant Schedule Problem

Before solving the minimum emission dispatch problem, we need to know which conventional power plants are available in summer and winter; in other words, we need to solve an annual plant schedule problem.

We use empirical monthly peak demand data of 2020 to estimation the monthly peak demand by 2025.

As a conservative estimation of the capacity value of VRE, we assume that they can provide 3 GW of peak residual load shedding during July and August, and 1.5 GW during May and September. For other months the reserve capacity must be fulfilled by DR, storage, conventional and DRE power plants.

Annual Plant Schedule Problem

Assumptions for the schedule problem:

1. All conventional power plants need at least 1 month of maintenance in a year.
2. For every month, the available capacity must be greater or equal to 110% of the projected peak demand (if this cannot be met, we lower the criteria until a feasible solution exists).
3. For air pollution months (October to March), total assigned coal capacity cannot exceed 8 GW. Additional regulatory constraints on Taichung and Hsinta coal power plants are also taken into account.
4. In the congestion scenario there will be an additional constraint on the maximum available power capacity at Datan power plant at any given time.

Annual Plant Schedule Problem

$$\max Reserve_{\min}$$

$$\sum_i cpp_{\max,i} \cdot u_i(t) \geq 1.1 \cdot RL_{\max}(t) \forall t$$

$$\sum_{i \in \{Coal\}} cpp_{\max,i} \cdot u_i(t) \leq Coal_{max}(t) \forall t$$

$$\sum_{i \in \{Datan\}} cpp_{\max,i} \cdot u_i(t) \leq Datan_{max}(t) \forall t$$

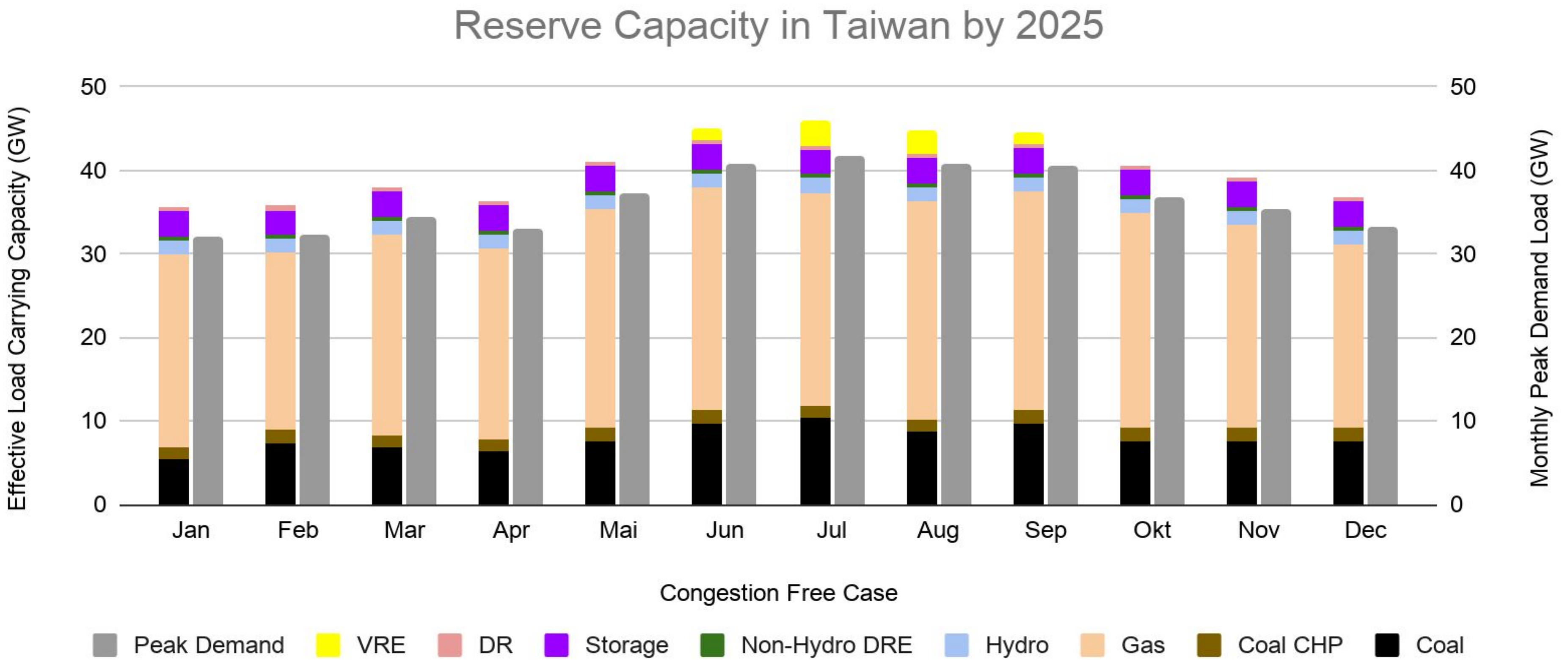
$$\sum_t m_i(t) = 1 \forall i \qquad m_i(t) + m_i(t-1) + u_i(t) \leq 1 \forall i, t$$

$$Reserve_{\min} \leq \sum_i cpp_{\max,i} \cdot u_i(t) - RL_{\max}(t) \forall t$$

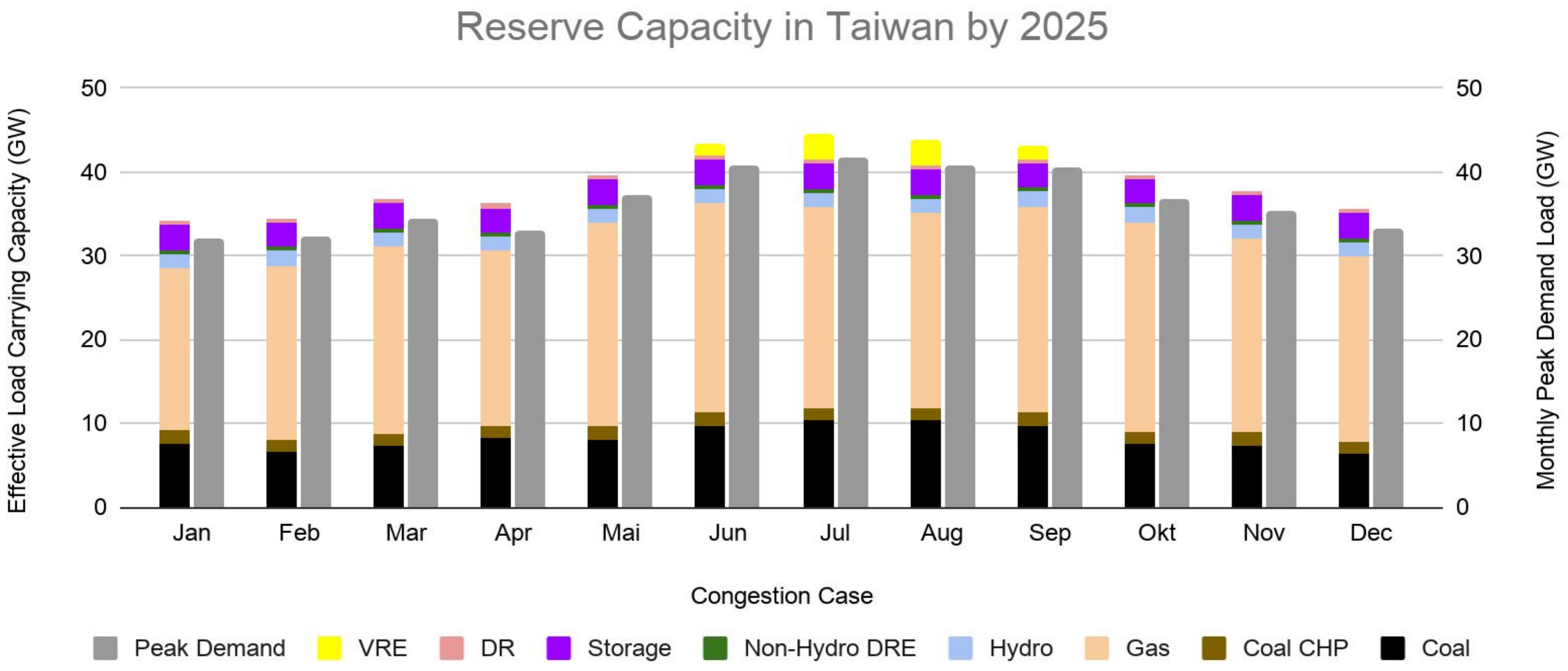
$$u_i(t) \in \{0,1\} \quad m_i(t) \in \{0,1\} \quad \forall i, t$$

Annual Plant Schedule Problem

In the congestion free case, available capacity can be kept above 10% throughout the year.

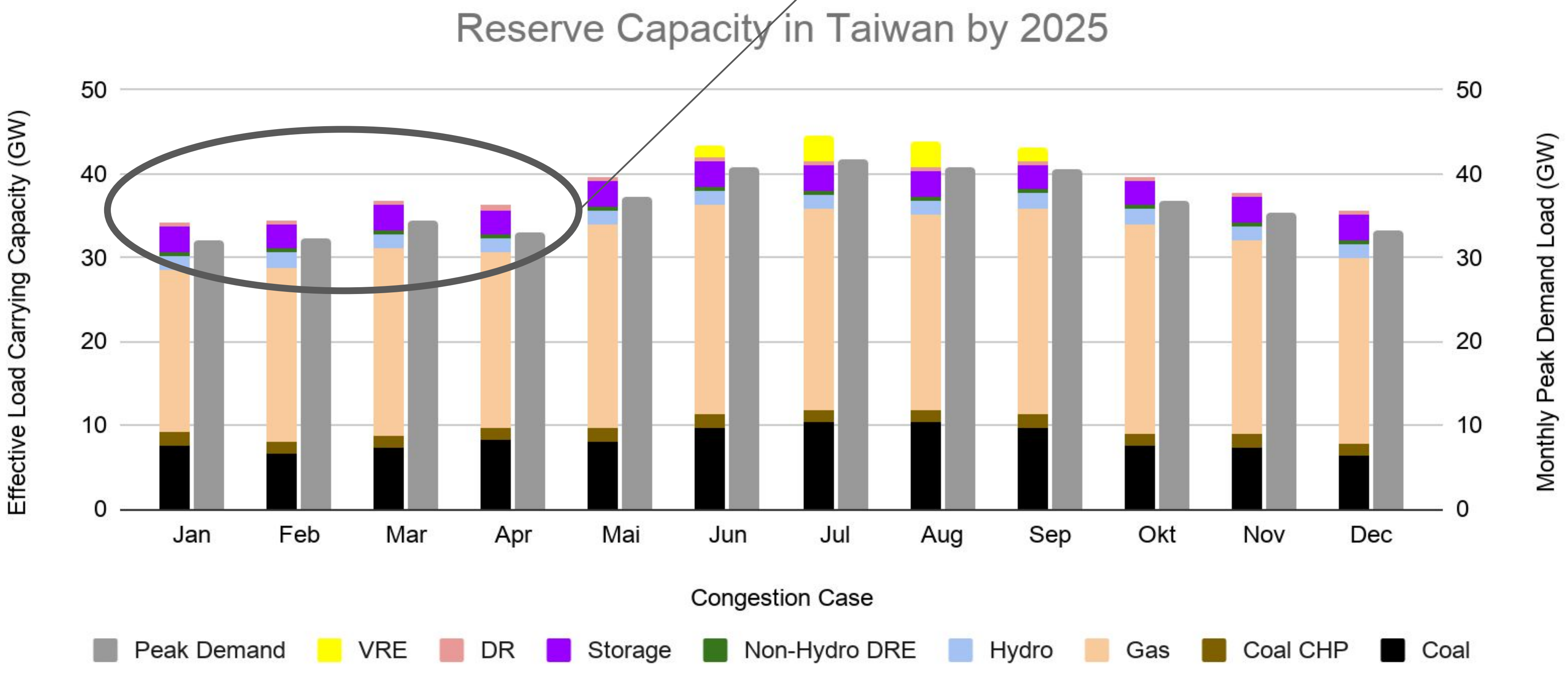


Annual Plant Schedule Problem



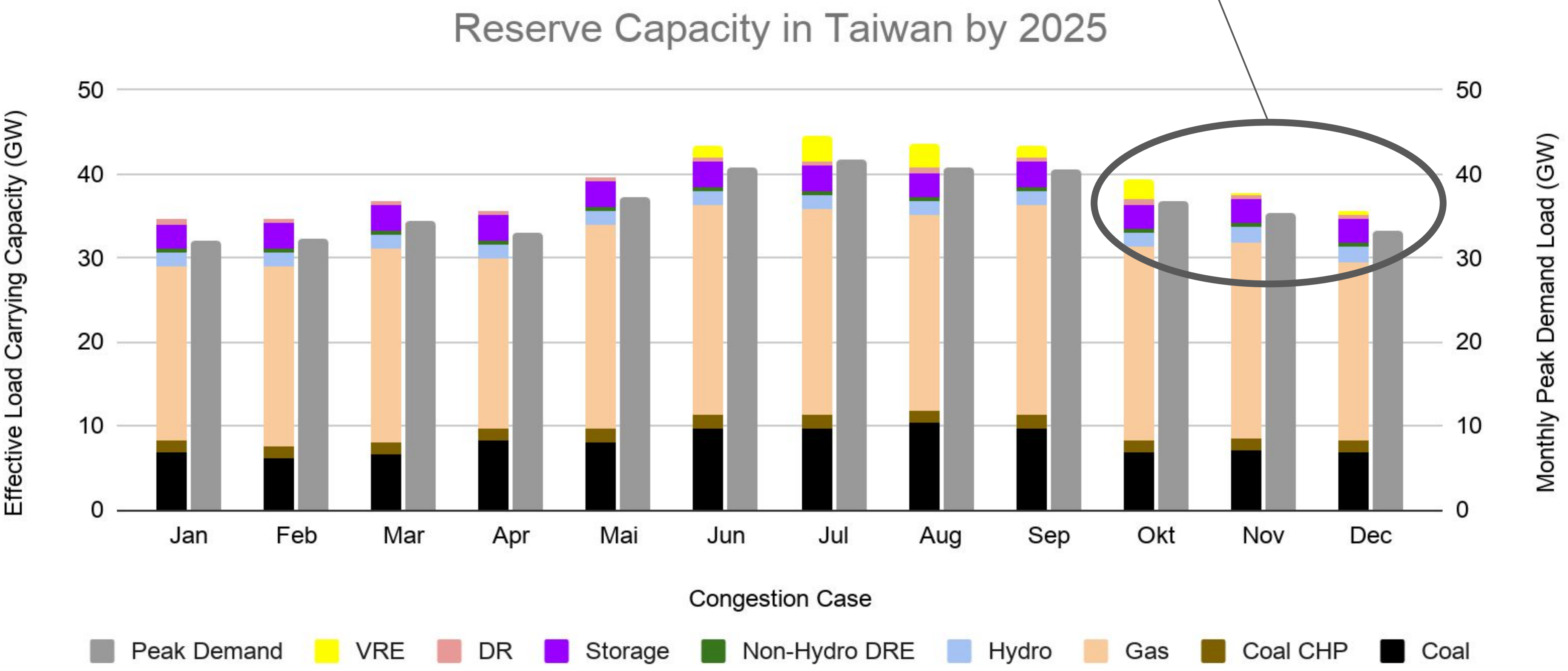
Annual Plant Schedule Problem

By scheduling more maintenance in the winter, available reserve can be kept around 6% throughout the year in the congestion case; the impact of congestion on the minimum is 3.90%.



Annual Plant Schedule Problem

Taking the capacity value of offshore wind power plants in autumn and winter into account does not alter the result significantly.



Annual Schedule Problem Results: Comparison

	Congestion Free Case	Congestion Case
Min Reserve Margin Ratio	10.01%	6.11%
Min Month	August	June
Max Reserve Margin Ratio	10.79%	9.75%
Max Month	January	April

Annual Schedule Problem Results: Comparison

	Congestion Free Case	Congestion Case
Min Reserve Margin Ratio	10.01%	$\boxed{6.11\%}$
Min Month	August	
Max Reserve Margin Ratio	10.79%	9.75%
Max Month	January	April

Worst case impact delaying / cancellation of the terminal can have

Annual Plant Schedule Problem: Results Passing

The solution to the annual plant schedule problem will be passed to the main dispatch problem; it will correspond to the available conventional power plants at the modeled time slice.

RL Profile and Preprocessing

Before solving the minimum emission dispatch problem, we need to model the residual load profile. In this step the dispatch of storage units and hydroelectricity power plants are also modeled, and the residual load profile will be smoothed accordingly.

RL Profile and Preprocessing

We use empirical demand and VRE (solar PV, onshore wind, and offshore wind) capacity factor data from 23-24 July, 2020 to generate a 48-hour-long demand load and residual load profiles for the impact study. Loss data points are linearly interpolated.

We assume that there will be 20 GW of solar PV, 0.8 GW of onshore wind, and 5.5 GW offshore wind by 2025.

RL Profile and Preprocessing

Hydroelectricity and storage will be scheduled to minimize the maximum residual load during the period.

For hydroelectricity, we will only consider reservoir hydro (1.835 GW): we assume the daily average capacity factor of these power plants are 17.9% (empirical value of July 2020) but the operator can decide when to dispatch the water so long as the daily electricity output does not exceed the capacity factor mentioned above. An power limit of 0.6 GW is empirically observed and will also be set in the problem.

RL Profile and Preprocessing

For storage, we assume the SOC to be 50% at the beginning and the end of modeling (we set maximum available to be energy stored after charging continuously at full capacity for 24 hours for pump storage and 4 hours for batteries). We also set maximum charge of PS to 2.5 GW and discharge to 1.8 GW according to empirical data. Power capacity of BAT is set to 0.59 GW. Also, to avoid abrupt change, we impose addition ramp constraints (0.1 * P_max) on storage and hydroelectricity power plants.

Once the optimal peak residual load is obtained, we polish the solution so that the cycling energy loss is minimized. Then, we polish the solution again, so an imaginary price spread (assumed to be the original RL) is minimized.

RL Profile and Preprocessing: Original Problem

$$\min RL_{max}$$

$$RL(t) + \sum_{s_i}(P_{s_i,dc}(t) - P_{s_i,ch}(t)) + HE(t) = RL_0(t)\forall t$$

$$SOC_{s_i}(t+1) = SOC_{s_i}(t) - \frac{P_{s_i,dc}(t)}{\eta_{s_i,dc}} + P_{s_i,ch}(t) * \eta_{s_i,ch}\forall s_i, t$$

$$0 \leq SOC_{s_i}(t) \leq SOC_{\max,s_i}\forall s_i, t$$

$$0 \leq P_{s_i,dc}(t) \leq P_{max,s_i,dc}\forall s_i, t$$

$$0 \leq P_{s_i,ch}(t) \leq P_{max,s_i,ch}\forall s_i, t$$

$$0 \leq HE(t) \leq HE_{\max,power}\forall t$$

$$\sum_{t} HE(t)\Delta t \leq HE_{\max,energy}$$

$$RL(t) \leq RL_{max}\forall t$$

RL Profile and Preprocessing: Intermediate Problem

$$\min \sum_{t} \left(\frac{1}{\eta_{s_i,ch}} - 1 \right) \cdot P_{s_i,ch}(t) + (1 - \eta_{s_i,dc}) \cdot P_{s_i,dc}(t)$$

$$RL(t) + \sum_{s_i} (P_{s_i,dc}(t) - P_{s_i,ch}(t)) + HE(t) = RL_0(t) \forall t$$

$$SOC_{s_i}(t+1) = SOC_{s_i}(t) - \frac{P_{s_i,dc}(t)}{\eta_{s_i,dc}} + P_{s_i,ch}(t) * \eta_{s_i,ch} \forall s_i, t$$

$$0 \leq SOC_{s_i}(t) \leq SOC_{\max,s_i} \forall s_i, t$$

$$0 \leq P_{s_i,dc}(t) \leq P_{max,s_i,dc} \forall s_i, t$$

$$0 \leq P_{s_i,ch}(t) \leq P_{max,s_i,ch} \forall s_i, t$$

$$0 \leq HE(t) \leq HE_{\max,power} \forall t$$

$$\sum_{t} HE(t) \Delta t \leq HE_{\max,energy}$$

$$RL(t) \leq RL_{max} \forall t$$

RL Profile and Preprocessing: Polishing Problem

$$\min \sum_t RL_0(t) \cdot (\frac{P_{s_i,ch}(t)}{\eta_{s_i,ch}} - P_{s_i,dc}(t) \cdot \eta_{s_i,dc})$$

$$RL(t) + \sum_{s_i} (P_{s_i,dc}(t) - P_{s_i,ch}(t)) + HE(t) = RL_0(t) \forall t$$

$$SOC_{s_i}(t+1) = SOC_{s_i}(t) - \frac{P_{s_i,dc}(t)}{\eta_{s_i,dc}} + P_{s_i,ch}(t) * \eta_{s_i,ch} \forall s_i, t$$

$$0 \leq SOC_{s_i}(t) \leq SOC_{\max,s_i} \forall s_i, t$$

$$0 \leq P_{s_i,dc}(t) \leq P_{max,s_i,dc} \forall s_i, t$$

$$0 \leq P_{s_i,ch}(t) \leq P_{max,s_i,ch} \forall s_i, t$$

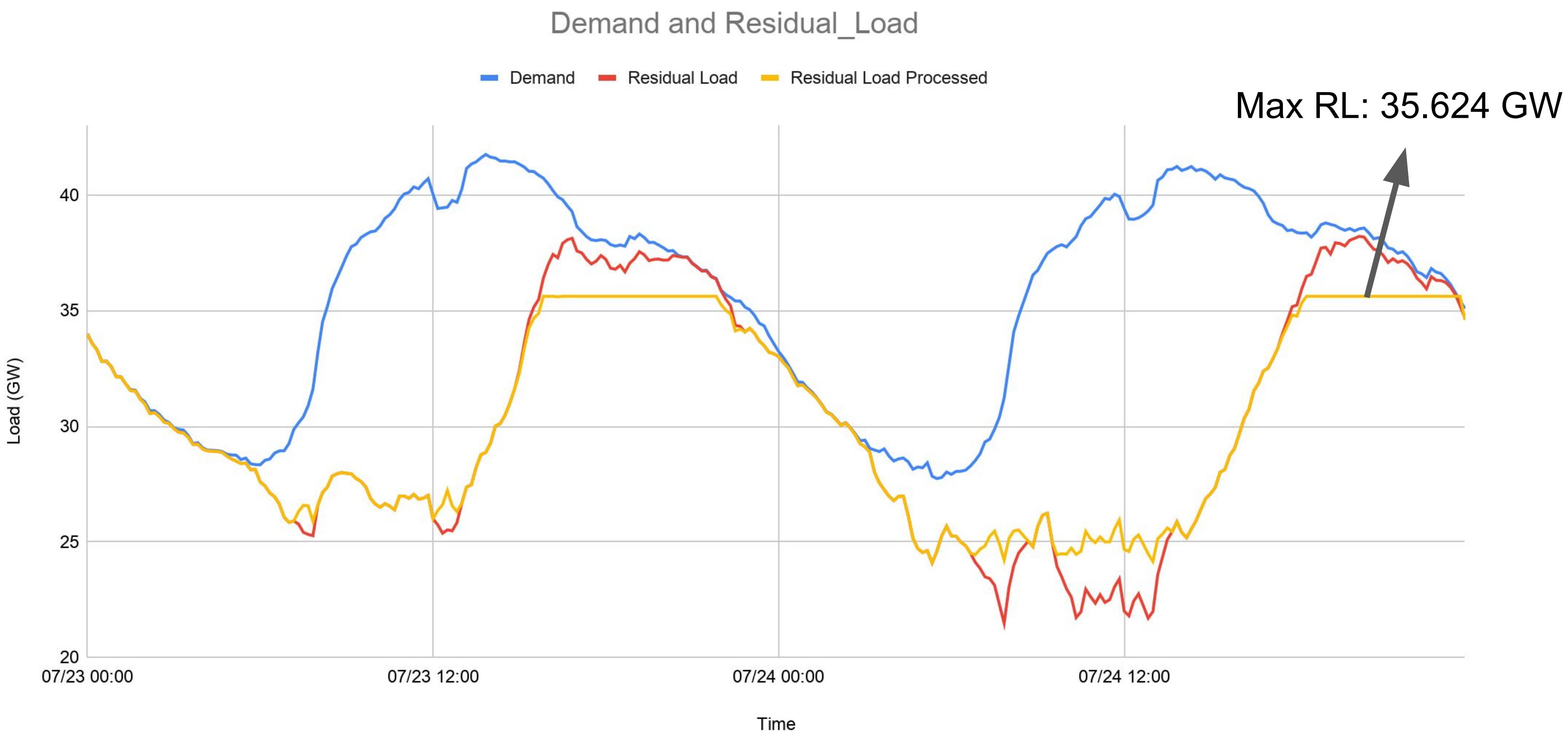
$$0 \leq HE(t) \leq HE_{\max,power} \forall t$$

$$\sum_t HE(t) \Delta t \leq HE_{\max,energy}$$

$$RL(t) \leq RL_{max} \forall t$$

$$\sum_t \left(\frac{1}{\eta_{s_i,ch}} - 1 \right) \cdot P_{s_i,ch}(t) + (1 - \eta_{s_i,dc}) \cdot P_{s_i,dc}(t) \leq Loss_{min}$$

RL Profile and Preprocessing: Results

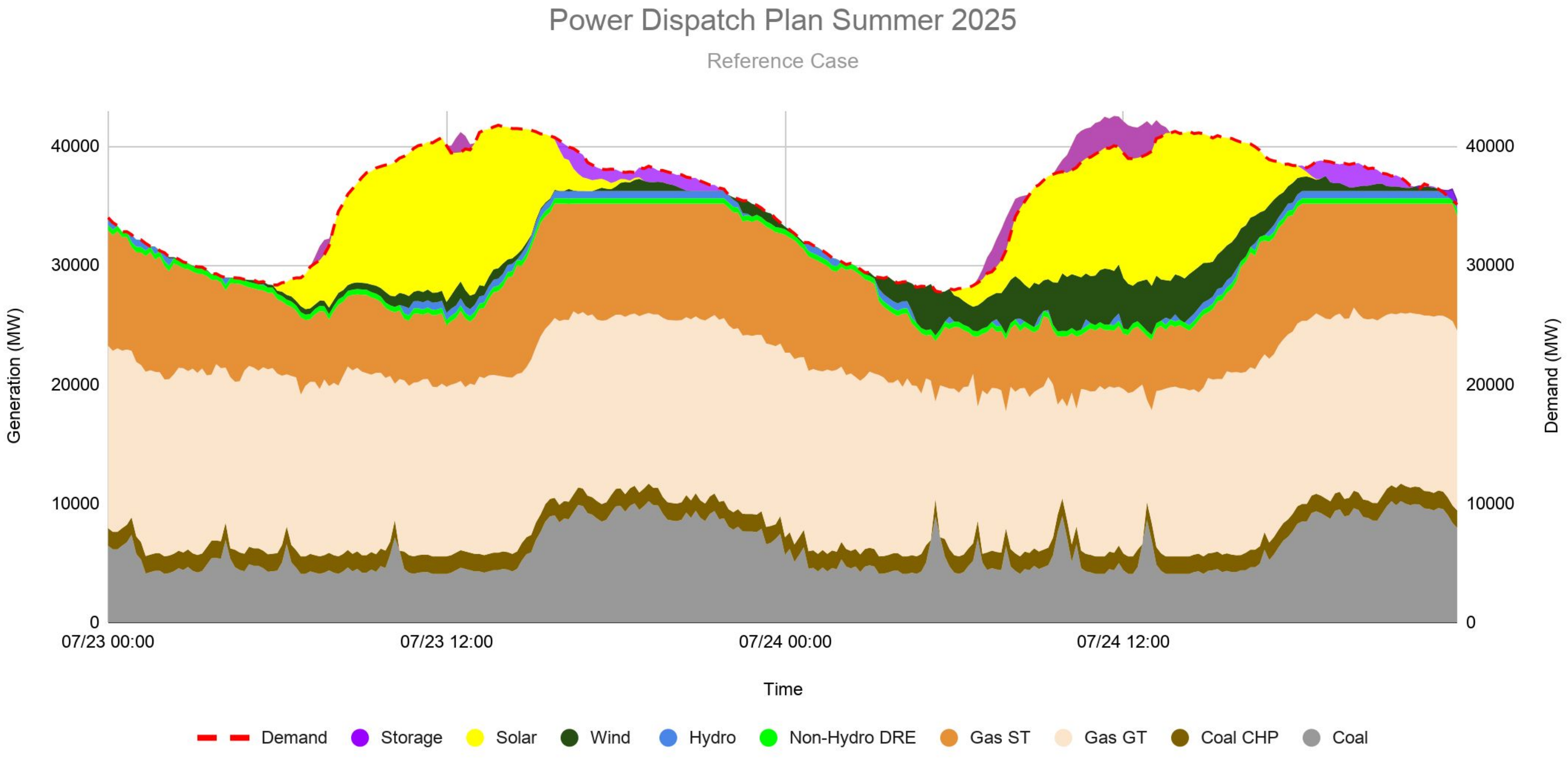


RL Profile and Preprocessing: Remaining Flexibility

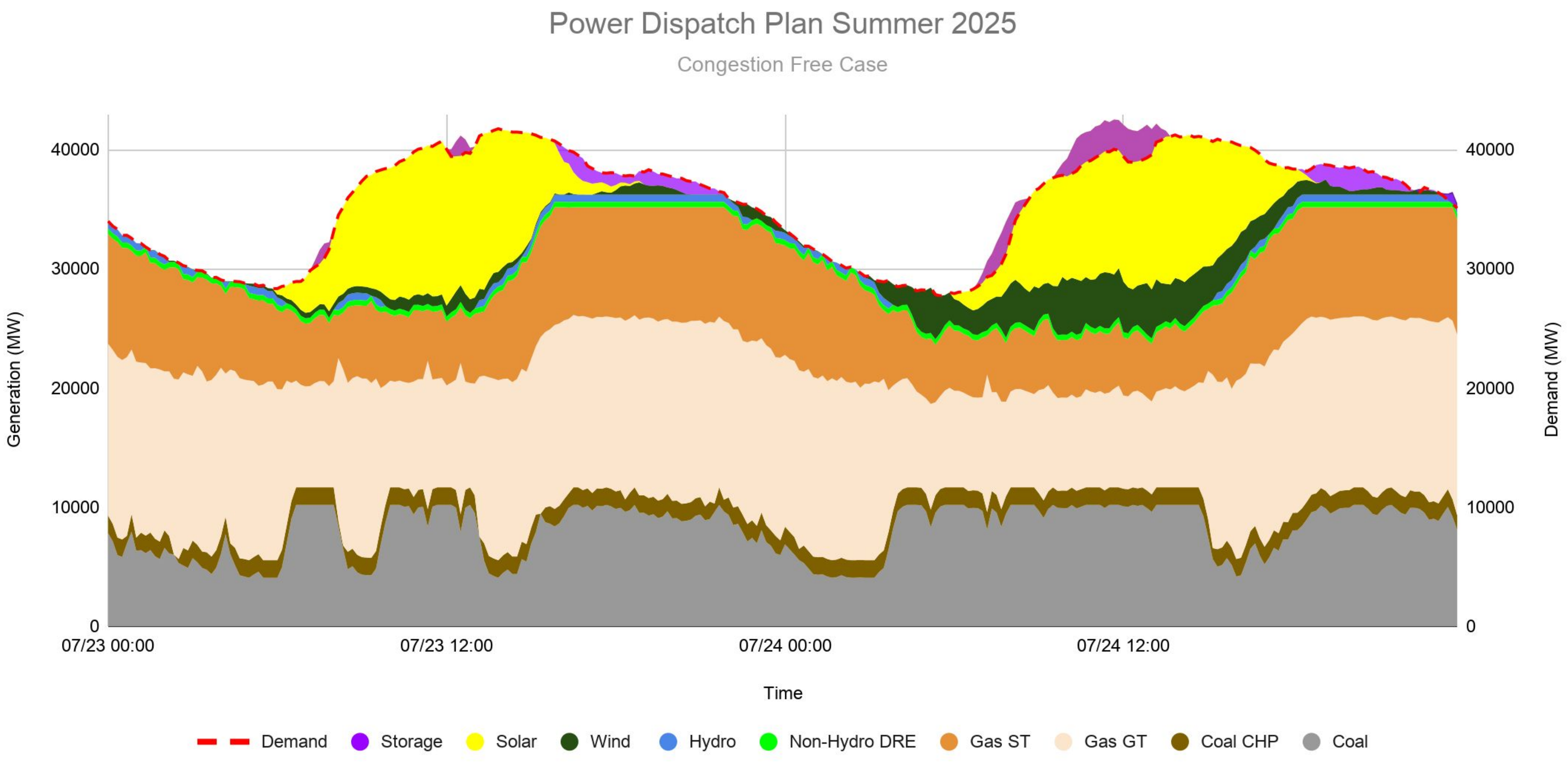
After the preprocessing problem is solved, there might be remaining flexibility regarding the power and energy output of hydroelectric power plants. This flexibility will be calculated and passed on to the main dispatch problem.

Since Taipower assumes 87% effective load carrying capacity factor of reservoir hydro, at any moment the upward flexibility of hydroelectricity power plants can be assumed to be 1.835 * 0.87 GW minus the scheduled power output. This can be added to the positive control reserve, so at any moment hydroelectricity power plants can contribute to at least 0.996 GW of positive control reserve.

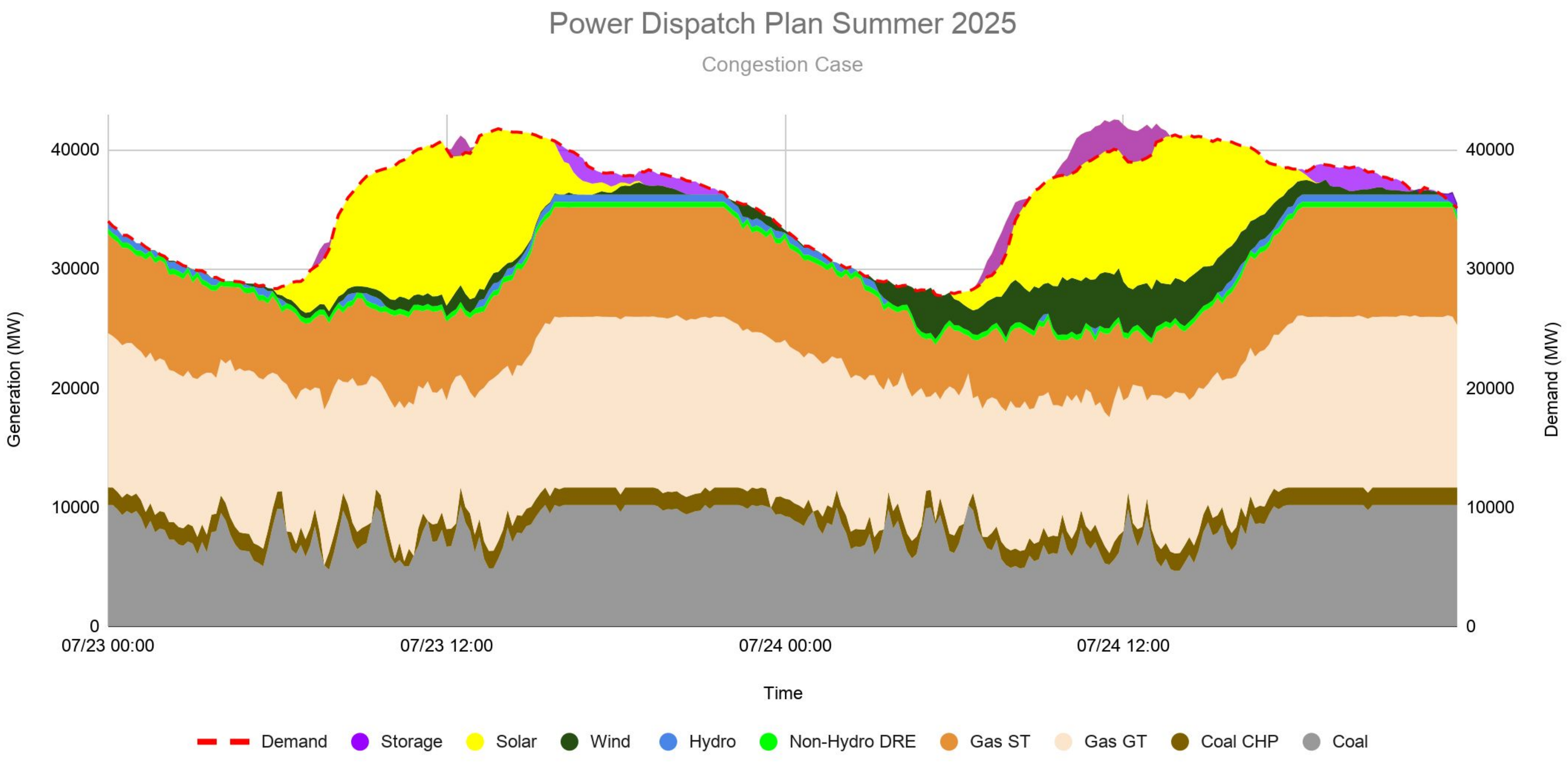
Results: Dispatch Problem (Summer)



Results: Dispatch Problem (Summer)



Results: Dispatch Problem (Summer)



Dispatch Problem Results Summer: Comparison

	Reference	Congestion Free	Congestion
Electricity Generation from Coal (GWh el)	292	388	395
Electricity Generation from CHP (GWh el)	69.3	68.4	66.2
Total Coal Consumption (GWh th)	848	1090	1104
Operation Emissions (kton CO2 eq)	699	729	733
Start-up Emissions (kton CO2 eq)	0	0	0
Total Emissions (kton CO2 eq)	699	729	733

Dispatch Problem Results: System Reliability of Different Cases

In this assessment report, due to the nature of the modeling only prediction error and power plant outage can be considered. Transmission line outage, gas infrastructure outage, and other sources of contingencies are not considered.

To give a conservative estimation, we assume that unscheduled outage happens at a frequency of 1 power plant per week. We assume prediction error sd of RL is 0.5 + max(0.1 * VRE, 0.5) GW.

Monte Cairo simulations with 1 million samples for each case are conducted to find the reliability statistics.

Dispatch Problem Results: System Reliability of Different Cases

Summer (20:10 24 July)			
	Reference	Congestion Free	Congestion
Probability of Inadequate Positive Control Reserve	2.20 * 10^(-5)	1.60 * 10^(-5)	7.89 * 10^(-4)
Expected Inadequate Positive Control Reserve Capacity (MW)	2.89 * 10^(-3)	4.46 * 10^(-3)	2.06 * 10^(-1)
Probability of Inadequate Negative Control Reserve	0	0	0
Expected Inadequate Negative Control Reserve Capacity (MW)	0	0	0

Dispatch Problem Results: System Reliability of Different Cases

Summer (20:10 24 July)			
	Reference	Congestion Free	Congestion
Probability of Inadequate Positive Control Reserve	2.20 * 10^(-5)	1.60 * 10^(-5)	7.89 * 10^(-4)
Expected Inadequate Positive Control Reserve Capacity (MW)	2.89 * 10^(-3		
Probability of Inadequate Negative Control Reserve	0	0	0
Expected Inadequate Negative Control Reserve Capacity (MW)	0	0	0

Normally the reliability criteria is between 10^(-4) and 10^(-3); even the congestion case is still within this range.

Mitigation Approaches

To mitigate the coal reduction impact of not building the gas terminal as planned, there are three main aspects policy makers will consider:

- ➢ Alternative Gas Supply Options
- ➢ Accelerated Renewable Deployment
- ➢ Ambitious Energy Efficiency and Conservation Policies

Mitigation Approaches: Comparison

	Alternative Gas Supply	**RE+**	**EE+**
Possible Policies or Plans in Near Term	Floating Storage Regasification Unit (FSRU)	Broader and stricter renewable obligation for energy intensive industries and other entities	Carbon pricing; local marginal pricing for industrial areas
Corner Solution Requirements	Unavailable about 10 days annually due to typhoons, so to fully mitigate the coal reduction impact the maximum import capacity must be increased by 2.81% compared with the original plan.	To completely fill the gap without addition coal consumption about 10.3 TWh of renewable energy is required, which translates to around 9.03 GW of solar PV or 2.86 GW of offshore wind. If only carbon emission is considered then only 55.2% of this amount is required.	To completely fill the gap without addition coal consumption about 10.8 TWh of gross electricity demand needs to be reduced (around 3.51% of the original projected gross electricity demand by 2025). If only carbon emission is considered then only 55.2% of this amount is required.
Advantages	Reduces costs and ecological impacts; can be deployed to other ports according to the overall gas supply situation in Taiwan later.	Non-regrettable (we will need to deploy RE anyway); avoids significant ecological impacts	Non-regrettable (we will need to set these policies eventually); completely avoids ecological impacts
Potential Obstacles	Still fossil fuel infrastructure and subject to stranded asset risk; additional safety concern during typhoons.	Opposition from energy intensive industries; corner solution means increasing the planned installation rate of VRE by 45.2% (solar PV) to 52.0% (offshore wind) until 2025.	Opposition from energy intensive industries; price elasticity of electricity highly uncertain.

Mitigation Approaches: Optimal Pathway

Obviously an optimal mitigation pathway will be a combination of all the possible approaches.

For example, in the end 50% of the coal reduction impact will be mitigated with a smaller FSRU project, 25% with additional wind and solar, 25% with higher carbon tax and local marginal pricing for industrial areas in Hsinchu and Taoyuan.

Further socio-economic assumptions and parameters will be needed to determine the optimal pathway. This is beyond the scope of this assessment report.

Conclusions

1. A rough estimation suggests that the delay / cancellation of Datan conventional gas terminal will result in 3.28 million tonnes of additional coal consumption and 4.36 million tonnes of additional carbon emissions annually.

2. Under the congestion free case, the minimum reserve margin ratio for each month can be kept above 10%, and dispatch modeling suggests that power system reliability will not be affected even if Datan conventional gas terminal is delayed / cancelled.

Conclusions

3. Under the congestion case, the minimum reserve margin ratio for each month will decrease 3.90 % to 6.11% if Datan conventional gas terminal is delayed / cancelled. However, dispatch modeling suggests power system reliability is still within tolerable range during peak residual load time periods in summer.

4. Some of the possible approaches to cope with the potential coal reduction gap due to delay / cancellation of the terminal are shown. The optimal pathway will most likely be a combination of several of these approaches.

Reference

Latest (Dec. 2020) Energy Statistics in Taiwan:
《能源統計月報》, Bureau of Energy, Feb 2021

Latest (2019) Carbon Emission Statistics in Taiwan
《溫室氣體排放係數管理表6.0.4版》, Environment Protection Agency

Effective Load Carrying Capacity Factors and CHP Data
Taipower website.

Details of the Conventional Power Plant Fleet in Taiwan
2019 annual reports of the private and public utilities in Taiwan. They were published in March 2020.

Reference

Technical Parameters for Conventional Power Plants

“Generator Technical and Cost Parameters”, ElectraNet, July 2020

“On Start-up Costs of Thermal Power Plants in Markets with Increasing Shares of Fluctuating Renewables”, Wolf-Peter Schill, Michael Pahle and Christian Gambardella, Deutsches Institut für Wirtschaftsforschung, 2016

“Flexibility in thermal power plants - With a focus on existing coal-fired power plants”, Agora Energiewende, 2017

LP Solver Used for the Modeling and Original Data

The LP problem in RL pre-processing was solved with lpsolve.

The MILP problems of annual plant scheduling and minimum emission dispatch were solved with GCG - SCIP.

The dispatch problem was too complex to solve so we assumed that all the conventional power plants were on line at any given time; the problem was thus reduced to a LP.

The data for conventional power plant, DRE, and storage fleet by 2025, and the results of the power system dispatch modeling can be found here.